Innovative Methods for Integrating Utility and Production Automation Systems

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INTRODUCTION

Integrated steel facilities, as well as mini-mills, depend on reliable electric power in order to maintain production targets in an intensely competitive marketplace. At the same time, these facilities seldom integrate detailed energy usage with other product cost metrics, even though electric power is one of the largest product cost contributors. Although insufficient technology and longstanding organizational barriers have been primary contributors to the lack of integration, recent technological advancements are starting to reverse the trend. This paper addresses the developments in electric power control and communications systems that provide for much greater integration with other plant control systems. It also discusses methods by which plant operators can take advantage of these technologies to make business and operational improvements.

Electric Power Usage and Cost Impact

In asset-intensive production environments like steel facilities, management review of technology improvement programs is naturally rigorous. Whether operators are evaluating new production equipment or improved power system control technology, they need to show tangible productivity, quality, or cost improvements in order to gain approval for such projects. For this paper, total electrical utilization data and per-ton cost metrics are a useful background to consider along with new technologies.

Tables I and II demonstrate the prominence of electricity use in the steel industry. In some geographic regions, it can account for as much as 40 percent of the cost of production.[1] Plant managers recognize this and have a clear understanding of plant-level electrical costs; this information has helped plant managers justify many energy-saving projects in mills over the past decade. Examples of this include lighting improvements and installation of variable speed motors. However, very few facilities have implemented instrumentation in order to manage electrical use at the unit or product level.

Table I.   Electrical utilization by industry[2]

Industry Subsector	Net Electricity Used (million kWh)
Iron and Steel Mills	51,198
Alumina and Aluminum	44,536
Fabricated Metal Products	41,965
Petroleum Refineries	37,335
Paper Mills	32,358

Table II.   Iron and steel production utility costs[2]

Fuel	Normalized Cost (dollars per ton)
Electricity	25
Natural Gas	21.1
Coal	12.6
Residual Fuel	0.04
Coke and Breeze	18.6

Historical and Organizational Barriers

Historically, technology differences have created significant barriers to the integration of plant power systems and production control systems. For the most part, large electric utilities have driven the operational practices of power systems: equipment vendors have developed products that advanced the technology and satisfied the operating practices of those utility customers. At the same time, process and discrete industries have worked with technology suppliers to develop control systems appropriate for their own operating requirements.

These independent development paths have made it difficult to integrate utility and industrial control system equipment. This difficulty can be illustrated by communications protocols. With the exception of Modbus®, which has some application in utility systems, common industrial protocols are not routinely used in power systems. The reverse is also true. We can understand the reason for this easily: vendors and industry associations develop protocols such that common data are objectified in a way that suits state-of-the-art operating practices. Utility and industrial control systems have unique requirements, so the development of protocols diverged over time. While the cause is easy to understand, the resulting lack of integration is difficult for automation professionals to overcome.

Another barrier to system integration has been organizational structures within steel mills. Power distribution engineering and production automation groups do not normally work closely together or share engineering systems. Without clear management directives or benefit statements, it is difficult for these groups to span organizational boundaries and develop integrated systems during facility enhancement projects.

New Opportunities

The penetration of information technology (IT) communications technologies into automation and plant-floor devices is beginning to address long-standing protocol integration issues. Simultaneously, energy capacity concerns and environmental regulations are providing organizational and financial support for integration projects that may have been difficult to justify in the past. However, these external catalysts may cause facility engineers to implement smart grid objectives or active demand management systems within the plant without a clear performance goal or detailed understanding of the available technologies.[3] In the following sections, we evaluate available technologies and how they can be used to increase power system integration and improve overall plant performance and profitability.

PROTECTION AND MONITORING TECHNOLOGY

Figure 1 illustrates a segment of an example power system with protection and monitoring equipment that engineers commonly deploy in industrial power systems. Notice that the protection, metering, and monitoring devices are distributed throughout the system. In considering integration and communications technologies, we need to understand how different technologies will perform in a distributed network.
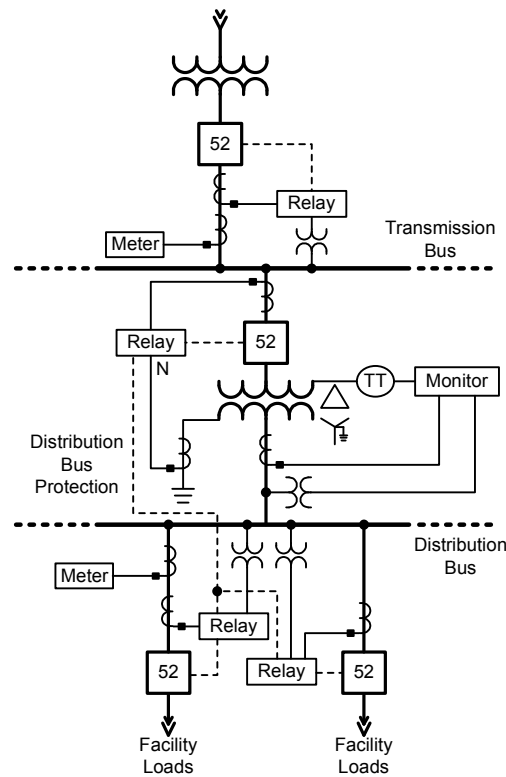

Figure 1.   Example power system protection and monitoring architecture

Protective Relays

In the past, protective relays were electromechanical devices; multiple single-function relays each enabled one protection element (e.g., a directional phase-to-ground element) and functioned cooperatively to protect power system apparatuses. Such relay designs were ingenious and effective, but unfortunately they were also very complex, expensive, and difficult to maintain. Modern implementations utilize microprocessor-based multifunction relays such that one instrument replaces many electromechanical relays. Microprocessor-based relays not only reduce installation cost (because of fewer devices, smaller panels, and less wiring) but also improve performance and reliability through automated self-checking and elimination of relay calibration.[4]

If we consider communication and integration, microprocessor-based relays provide significant advantages compared to electromechanical devices. Relay designers have created innovative methods to use the inherent processing and memory capabilities of microprocessor devices to store and communicate a wide variety of power system operating information for supervisory control and data acquisition (SCADA) and performance analysis purposes. Relays delivered by manufacturers today routinely include Ethernet and serial ports plus a variety of communications protocols.

Revenue-Class Meters

If we desire to manage and control a process parameter in an iron or steel facility, then the parameter must be either directly measured or estimated in order to provide feedback to the control system. The same requirement applies to electricity use and power quality, but the meters deployed in a plant generally do not include the features needed to incorporate metering data into plant operations.

The meters installed by local supply utilities are commonly more advanced, with some ability to measure power factor and harmonics in addition to real power demand. However, distribution meters in the plant traditionally have been inexpensive and simple; they measure only real power demand and do not have communications functionality. Management can only evaluate consumption as often

as they are willing to send a technician to read and record the meter values. The combination of infrequent metering feedback and lack of metering integration practically requires that electricity be treated as a bulk commodity rather than a major component of production costs.

Similar to the developments we discussed for protective relays, modern meters are microprocessor-based and more reliable than electromechanical devices, and they include advanced recording, reporting, and integration features.

Equipment Monitors

Asset management, equipment monitoring, and predictive/preventive maintenance are all popular topics for a variety of industries. Users desire to maximize the productivity and longevity of capital equipment while optimizing maintenance expenses. Digital industrial networking technologies, such as FOUNDATION™ fieldbus, help to achieve this objective by providing a mechanism to interleave equipment performance information with instrument input/output (I/O) information on the same physical channel. As an example, a valve positioner not only receives set point commands from a controller but also reports back operating parameters, such as movement initiation pressure and travel drift. By integrating this information into various asset management and preventive maintenance software packages, operators and maintenance personnel have the opportunity to identify impending equipment failures and schedule repairs before they cause production delays.

Similarly, protective relays, meters, and dedicated equipment monitoring devices provide integrated functions that utilities use to manage the health and maintenance of substation equipment. Figure 2 illustrates one implementation of this technology. The subject relay records the number of circuit breaker operations and the electrical current interrupted for each operation. The figure shows the three-zone wear model implemented in the relay to track the mechanical breaker wear based on actual utilization. Maintenance personnel can retrieve the report electronically to assist in planning equipment maintenance. Other substation devices provide health monitoring and asset management functions for transformers, generators, motors, and other primary electrical equipment.
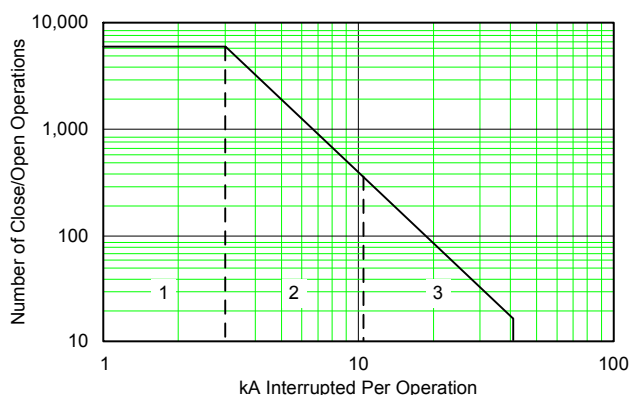

Figure 2.   Circuit breaker contact wear curve showing interruption regions[5]

METHODS OF INTEGRATION

Relay, meter, and control equipment vendors have developed many different proprietary and industry standard methods to integrate their devices in local-area and wide-area networks. As plant electrical engineers evaluate the integration of substation data into existing control systems, they will find a number of different architectures available. Each facility needs to investigate which integration technology best suits the local operating practices and business requirements.

Directly Connecting Substation Devices to Existing Control Network

As we have seen in previous sections, modern protective relays, meters, and monitoring devices include communications protocols and performance reporting functions that can be very useful for integrating power system information into existing process control systems. Popular human-machine interface (HMI) software applications support protocol drivers for a number of industry standard utility protocols, such as Distributed Network Protocol (DNP3). The starting point for integration may be as simple as connecting microprocessor-based relays and meters to an existing control network, as shown in Figure 3. Although the figure illustrates an Ethernet example, we can similarly use EIA-232 or EIA-485 networks and serial protocols to make these connections.
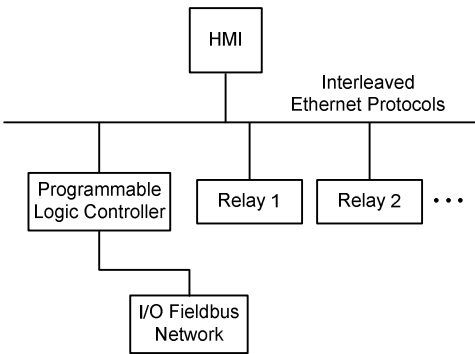

Figure 3.   Architecture with protective relays connected directly to the network

Once we have added communications connections from the relays to an HMI system, we can develop monitoring screens such as that shown in Figure 4. Such monitoring screens allow operations and maintenance staff to remotely monitor and control electrical equipment just as they would primary production equipment.
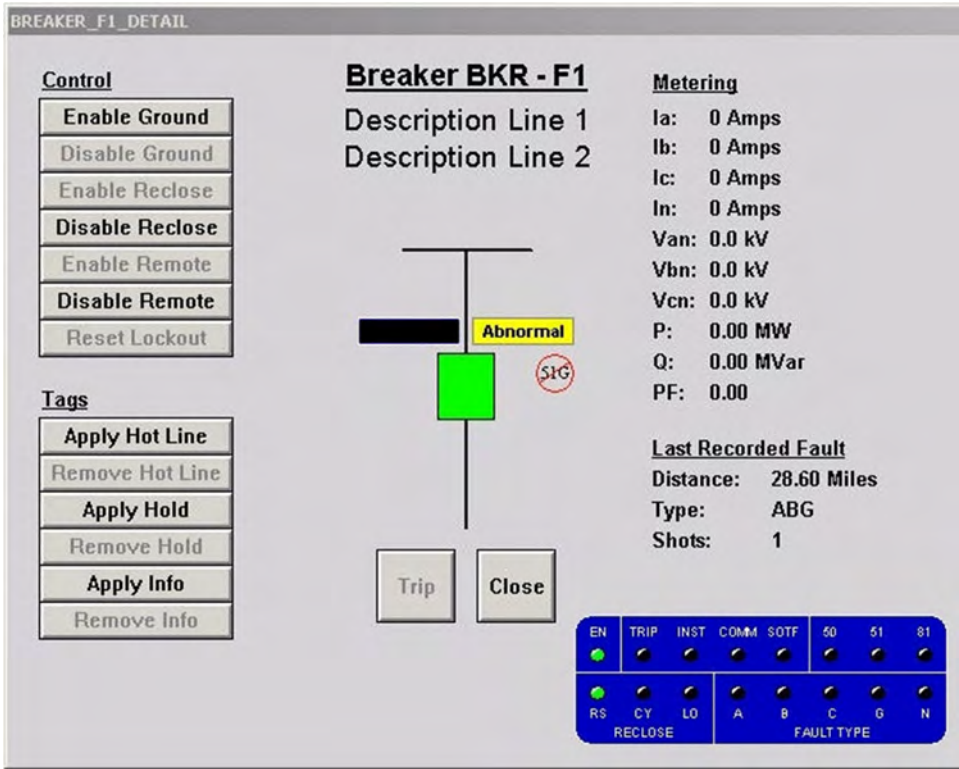

Figure 4.   Distribution feeder HMI screen

Logic and Communications Gateway

Even though Ethernet is becoming more common within control networking applications, high-voltage utility substations frequently have limited communications channels and low-bandwidth connections between the substation and master control centers. Equipment vendors have mitigated this network limitation by deploying automation controllers and rugged industrial computers in substations to

perform the functions of logic controllers and communications gateways. Figure 5 shows an example substation network topology using an automation controller.
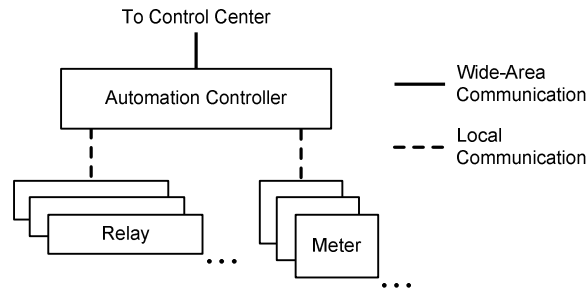

Figure 5.   Substation network using automation controller

Use cases for an automation controller or computer

An automation controller or rugged computer can facilitate substation integration at industrial facilities in a number of ways, including the following:

- The installed relays and monitoring devices may not all support the same communications protocol, so integrating them directly into a control network might prove challenging during configuration and commissioning. In that case, the automation controller or computer can collect information from the intelligent devices in their native protocols, concentrate the data for more efficient transmission, and create a single logical connection to the upstream control network in an appropriate protocol.

- A single communications cable to the substation is sufficient, which saves time and money and simplifies troubleshooting.

- The data concentration function makes the most efficient use of the communications channel. The protective relays may provide more information than needed for the application. Unused data tags in a control database add no value, create confusion, and increase HMI system cost. The automation controller or computer can filter unneeded tags and only send the tags required.

- Most automation controllers have a programmable logic engine similar to that found in a programmable logic controller. Whether used simply for signal scaling or for implementing custom control algorithms, logic processing is distributed locally in the substation.

Communications protocols used for data concentration

Once an automation controller is configured to collect information from substation devices, it needs a network connection to existing plant systems. As previously discussed, most programmable logic controllers, distributed control systems, and HMI packages include drivers for industry standard protocols such as Modbus or DNP3, thereby facilitating simple integration to an automation controller and providing acceptable performance. Another integration protocol is Object Linking and Embedding for Process Control (OPC), which is widely used at industrial facilities to connect plant-floor devices to enterprise systems. Until recently, OPC was limited to Windows®-based devices and had little inherent security capability. For example, the Distributed Component Object Model (DCOM) technology in OPC lacks the ability to transmit information over routed wide-area networks. Integrated plants are not commonly impacted by those limitations, but most utility substations are geographically remote and require firewalls and data transmission via virtual private networks (VPNs) if they are connected to Ethernet networks. Because of this, OPC has been used only by utilities with appropriate network infrastructure. OPC Unified Architecture (OPC-UA) is presently becoming available and has been expressly designed to be platform-neutral and have vastly improved security,[6] allowing it to integrate much more seamlessly with substation networks by using a rugged computer as a protocol gateway. Another emerging option for retrieving substation data is to create a direct database connection to the automation controller using Open Database Connectivity (ODBC). HMI and maintenance servers commonly support database connections, and connecting directly to an automation controller database eliminates "middleware" protocols and incorporates needed security technology.

IEC 61850

The lack of relay communications interoperability has been a pressing topic in the utility automation community for some time. In response, International Electrotechnical Commission (IEC) working groups designed and published the IEC 61850 standard in order to define a common industry method for communicating substation data. A number of vendors now make products that include IEC 61850, and they work together to implement and demonstrate interoperability.[7] Because IEC 61850 is based on Ethernet media

and includes a standard data model for command-control and peer-to-peer communications, its use can reduce wiring costs and engineering labor during automation system installation. With proper system design, users may effectively install an IEC 61850 substation network and benefit from standard messaging methods. In the previous example, Figure 5, the local communications could exist as IEC 61850 messages. The automation controller acts as a gateway and uses previously discussed protocols for communicating with the control center. However, there are some limitations and exclusions in IEC 61850 that designers need to understand and account for prior to system implementation.

The IEC 61850 standard includes support for a Substation Configuration Language (SCL) based on Extensible Markup Language (XML) that provides a standardized method for describing the data objects and information available from a given device. While SCL simplifies configuration of network messages, it does not address the configuration of protection elements or custom logic within the relays. Settings and logic in the substation devices still need to be configured using vendor-specific software tools.

IEC 61850 data objects, called logical nodes (LNs), provide standard naming conventions and structure for various common functions in relays. While the IEC 61850 documentation addresses how to sequence and name data within an LN, it does not address which LN will exist in a given device or which data elements will be implemented in a given LN. Some early adopters in the user community were confused by this and spent more time and money commissioning substations than they would have spent using traditional methods.

Not all relay data are conveyed through IEC 61850 messages for a given device. The standard does not require complete data coverage, and vendors have made independent choices about which relay data will be published using IEC 61850. Users in many applications will still require proprietary or other industry standard protocols, in addition to IEC 61850, in order to integrate the specific substation information needed. Even with these limitations, as long as users have a clear set of design expectations, IEC 61850 is an effective integration tool that is supported by many electrical equipment vendors. As the user community continues to request and support improvements to the standard, vendors will introduce more products and features with this technology.

Synchrophasors

Embedded substation protection and control devices must sample power system quantities very rapidly in order to perform their functions. Scan times of 1 millisecond are common, but some relays sample analog inputs much faster for specific applications. In most cases, the input samples between different relays are unsynchronized, but power system designers have recently started deploying relays that sample analog inputs synchronously using Global Positioning System (GPS) clocks as the synchronizing mechanism.[8] These relays use GPS time to produce a reference phasor sinusoid that reaches a maximum value at the top of each second. The relay can then measure every analog input with both a magnitude and an angle relative to the reference phasor. Additionally, each sample has a highly accurate time stamp. Measurements taken using this method are called synchrophasors. IEEE has developed the C37.118 protocol specifically for communicating synchrophasors along with time stamps. A number of relay models currently available provide this capability. Since two isolated relays would take synchronized measurements in relation to the same reference phasor, an engineer could directly calculate magnitude and phase differences for signals between those two relays in order to verify a system model between two substations.

BENEFITS OF INTEGRATION

Although we can derive value from understanding the available technology and integration methods for substation devices, we need to describe the expected business benefits before plant managers will support the deployment of any technology in the operation. This section evaluates a number of the previously discussed technologies and implementation methods in example use cases to make clear the operational benefits resulting from their use.

Upgrade Substation Devices to Improve System Control and Reliability

As we evaluate the benefits of distribution system integration, be aware that many of them depend on the installation of modern, intelligent power system monitoring and control equipment in the plant. Without these devices, we would need to install parallel power system I/O and networking devices in order to provide control system integration; this would make upgrade projects more expensive and complicated than desired. The question then becomes, can we derive direct and immediate benefits from using microprocessor-based relays, meters, equipment monitors, rugged computers, or automation controllers even before we consider benefits related to their integration with other plant systems?

Monitoring and control devices only add value to the operation when they are in service and functioning properly. System designers use the metric of "availability" as a standard for measuring the performance of a device in this regard. For this discussion, we will use the following definition of availability: "the steady-state probability that a component or system is in service."[9] Industry data show

that microprocessor-based relays have an availability between 10 and 80 times that of electromechanical relays. The primary purpose of a relay is to protect people and equipment from serious injury or damage in case of a fault. The possible insurance costs, equipment repair costs, and cost of lost production are all much higher if a fault should occur when a relay is out of service. Self-testing and alarm outputs of microprocessor-based relays are key contributors to their high availability rate. These devices constantly monitor the performance of hardware and software. If a problem exists, the relay will self-disable and notify operators via a digital output. Maintenance personnel will quickly know which device is out of service and can begin planning repairs. Electromechanical relays have no self-checking mechanism and can be out of service for an extended time without operator awareness. Users only discover the failure after a fault or the next time the relay is serviced and calibrated. Plants will gain immediate benefits from the reduced wiring, significant maintenance labor savings, and higher availability and performance that microprocessor devices deliver.

Improved Product Cost Modeling

Production of primary metals is a highly capital-intensive and cost-competitive venture. Facility management and technical staff have become quite skilled at identifying investments in automation that reduce labor and operating costs on the production floor. In order to prioritize the most effective investments, staff members need to work with an accurate product cost model that illustrates operating costs for each production unit as well as for different product types within a single unit. For example, operators carefully measure the use of zinc and the creation of waste dross on a galvanizing line. These measures may provide financial justification for upgrading air knives or edge baffles if they show a pattern of overcoating or poor coating distribution.

As we have previously discussed, electrical power is one of the largest production cost contributors, but it is seldom included in product cost models. On the other hand, if a facility installs revenue-class meters or relays with integrated metering functions at significant load centers throughout the plant and integrates the data from those meters into production recording metrics, then electrical utilization could be easily included in product cost information.

Once the integrated system is in place, the cost model will become a more accurate analysis tool for production planners and operations staff. They may find that operating practices and assumptions about product mix are no longer valid. The more accurate information would allow planners to schedule energy-intensive products during periods of off-peak electrical rates and blend the product mix toward higher margin selections.[10]

Asset Management

In addition to direct production costs, asset management is another large facility cost that plant managers try to control closely. A variety of software and consulting companies have developed products and services to assist in evaluating equipment performance, recommending maintenance tasks, scheduling parts and labor, and tracking costs. Asset management began with a trend toward preventive maintenance, where maintenance tasks shifted from repair of broken equipment to maintenance of equipment and logging of work on a regularly scheduled basis. Enhanced instrumentation and integration then allowed equipment operators to transition from scheduled preventive tasks to predictive maintenance tasks based on measured equipment performance. These improvements have provided measurable benefits in equipment availability, equipment performance, and reduced maintenance costs.[11]

Using the powerful monitoring and reporting features of substation protection and control equipment, plants have the opportunity to bring the benefits of asset management to power distribution, just as they pursue the same goals for primary production equipment. Automation controllers and dedicated substation computers allow users to simultaneously provide operational data to HMI systems and send asset management information to appropriate maintenance servers, as shown in Figure 6.
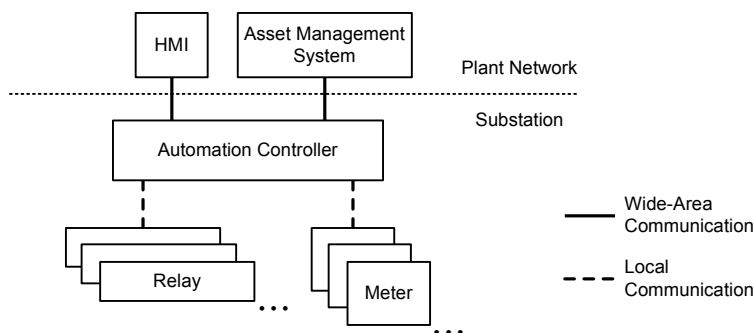

Figure 6.   Substation integration and asset management in a single network

To evaluate how monitoring equipment may be used for enhanced asset management of electrical equipment, consider a large power transformer for a rolling mill. Large transformers represent a significant capital expenditure that is critical to an operation. On-site replacement spares can be cost-prohibitive, and replacement units could easily require months for shipment. Plants have compelling business reasons to ensure the performance and maintenance of these devices. A transformer monitoring instrument exists that greatly facilitates asset management tasks for these units. The transformer monitor includes digital I/O, analog I/O, resistance temperature detector (RTD), and ac current and voltage inputs; programmable logic; and communications interfaces suitable for monitoring a transformer core and coil, cooling fan and pump banks, and on-load tap changer. The instrument is specifically designed to collect transformer signals and report custom asset information using integrated communications protocols. Additionally, it includes algorithms for calculating many derived process values, such as coil hotspot temperature, insulation aging factor, transformer loss of life, and through-fault wear. Maintenance personnel can use these innovative reports to identify needed service and repair work before issues begin to affect production. At the same time, personnel will not waste time on unneeded service based solely on a preventive calendar. Similar substation devices exist for monitoring circuit breakers, rotating machines, and capacitor banks.

Holistic Process View and Operational Signature

Power usage information displayed on HMI screens similar to Figure 4 allows operators to become familiar with the typical electrical loads experienced during certain production situations. Once they have a history and understanding of usage during normal operation, they are prepared to notice an abnormal condition before it becomes critical and requires a shutdown. As an example, fan motor loads could easily be integrated with fan speed and system pressure on the same HMI screen. An operator could quickly determine whether the motor amperes were increasing for a given operating condition. If an increase were observed, maintenance staff would then have time to identify root cause and prepare for repairs prior to a mechanical failure. As we discussed previously, these data may be used by asset management systems to automatically alarm upon certain conditions, but HMI systems give operators the opportunity to monitor and become familiar with equipment conditions that would be difficult to completely mimic in an asset management system. Providing power system data to operators may not immediately yield quantifiable benefits, but over time, their familiarity with baseline conditions will enable them to provide advance notification of looming production problems.

Electrical Islanding and Synchronism Control

A previous section described synchrophasors and how they are measured. Industrial plants are beginning to use synchrophasors to monitor on-site cogeneration units and to control grid interconnections in order to protect critical plant loads.[12] In this application, synchrophasor measurements are used as part of the control logic for plant circuit breakers and the governor controller on the cogeneration unit, as shown in Figure 7.
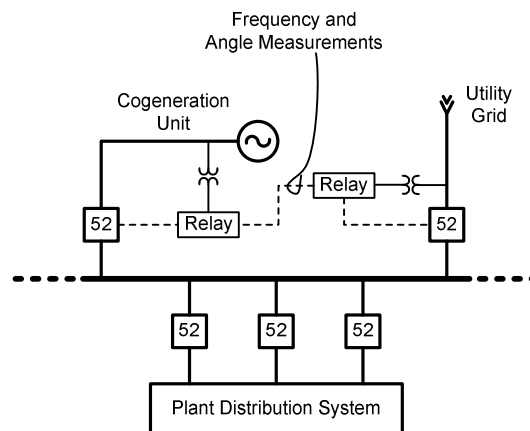

Figure 7.   Synchrophasor-based synchronizing and islanding system

If the control system detects disturbances on the bulk power system, it can automatically shed noncritical plant loads and disconnect from the external grid to create an islanded system within the plant. At a later time, when the grid has returned to normal operation, the control system needs to ensure that the cogeneration unit is properly synchronized prior to reconnecting the plant network. With synchrophasor measurements, the controls can use electrical frequency and angle to initiate islanding and also to ensure proper synchronization prior to reconnection. Without time-aligned measurement, no angular data are available.

If a plant integrates islanding controls with production facility controls, then facilities can initiate immediate and orderly shutdowns of certain processes prior to load-shedding actions. For example, cold mills or temper mills can be quickly stopped with minimal startup times. On the other hand, during certain critical periods, shedding an annealing furnace can cause many hours of lost production, even

if the electrical interruption is quite short. System designers can implement the load-shedding algorithm to account for these operating contingencies and selectively shut down portions of the plant while maintaining power to the critical loads.

SUMMARY

Electricity is one of the largest cost contributors in the production of iron and steel, but mills have seldom integrated the power distribution system such that usage can be tracked and controlled for each production unit or product. Technology and organizational barriers inhibited improvements to this situation. New substation control and automation devices, in conjunction with innovative integration technologies, provide a means to incorporate electrical power usage and performance with existing production automation systems. Utility demand management programs, smart grid publicity, and pending environmental regulations are simultaneously creating corporate interest in upgrading substation equipment.

In this paper, we have investigated new electrical system protection, metering, monitoring, and communications technologies that facilitate system integration. No individual product or technology will satisfy the requirements of every application, so the paper has addressed a range of methods and architectures that are useful in a variety of systems. Finally, we have considered how the application and integration of new substation technology could provide significant operational and cost benefits.

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